B o n n e v i l l e P o w e r A d m i n i s t r a t i o n
P o w e r B u s i n e s s L i n e

2002 Final Power Rate Proposal
7(b)(2) Rate Test Study

WP-02-FS-BPA-06
May 2000

BONNEVILLE
POWER ADMINISTRATION

SECTION 7(b)(2) RATE TEST STUDY

TABLE OF CONTENTS

COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
Alcoa	Alcoa, Inc.
Alcoa/Vanalco	Joint Alcoa and Vanalco
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CRITFC	Columbia River Inter-Tribal Fish Commission
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CTPP	Conditional TPP
CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones

DMP	Data Management Procedures
DOE	Department of Energy
DROD	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
Energy Services	Energy Services, Inc.
Enron	Enron Corporation
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
IPC	Idaho Power Company
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IJC	International Joint Commission

IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
ISC	Investment Service Coverage
ISO	Independent System Operator
JOA	Joint Operating Agency
Joint DSI	Alcoa, Vanalco, and DSI
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1,000 volts)
kW	Kilowatt (1,000 watts)
kWh	Kilowatthour
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service

NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Principles	Fish and Wildlife Funding Principles
Project Act	Bonneville Project Act
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People's Utility District
Puget	Puget Sound Energy, Inc.
PURPA	Public Utilities Regulatory Policies Act

RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
SPG	Slice Purchasers Group
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
VI	Variable Industrial Power rate
VOR	Value of Reserves
WAPA	Western Area Power Administration

WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. §839e(b)(2), directs the Bonneville Power Administration (BPA) to conduct, after July 1, 1985, a comparison of the projected rates to be charged its preference and Federal agency customers for their firm power requirements, over the rate test period plus the ensuing four years, with the costs of power (hereafter called rates) to those customers for the same time period if certain assumptions are made. The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain specified costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers). The two sets of rates are: (1) a set for the test period and the ensuing four years assuming that Section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in Section 7(b)(2), (7(b)(2) Case rates. Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates. Next, each nominal rate is discounted to the beginning of the test period of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average Program Case rate is greater than the average 7(b)(2) Case rate, the rate test triggers. The difference between the average Program Case rate and the average 7(b)(2) Case rate determines the amount to be reallocated from the 7(b)(2) Customers to other BPA loads in the rate proposal test period.

1.1 Purpose and Organization of Study

The purpose of this study is to describe the application and results of the Section 7(b)(2) rate test methodology. If the 7(b)(2) rate test triggers, the cost adjustment amount that is to be incorporated into the rate design process is calculated. The accompanying Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, contains the documentation of the personal computer-based models and data used to perform the 7(b)(2) rate test.

This study is organized into three major sections. The first section provides an introduction to the study, as well as a summary of the section 7(b)(2) Legal Interpretation and Implementation Methodology. The second section describes the methodology used in conducting the rate test. It provides a discussion of the calculations performed to project the two sets of power rates that are compared in the section 7(b)(2) rate test. The third section presents a summary of the results of the rate test for the 2002 rate. The financing benefits analysis is included as an appendix to this study.

1.2 Basis of Study

1.2.1 Legal Interpretation. As the first phase of its 1985 general rate case, BPA published the Legal Interpretation of Section 7(b)(2) of the Northwest Power Act, 49 FR 23,998 (1984). The Legal Interpretation is hereby incorporated by reference. Major provisions of the Legal Interpretation are listed below.

The 7(b)(2) Case is modeled by limiting the differences between the two cases to only five assumptions specified in Section 7(b)(2) and the unavoidable natural consequences of those assumptions on the results of ratemaking processes that remain the same between the Program Case and the 7(b)(2) Case.

BPA will reallocate costs resulting from the rate test trigger, pursuant to section 7(b)(3) of the Northwest Power Act, in a manner that is consistent with section 7(a) of the Northwest Power Act.

Applicable 7(g) costs are subtracted from the Program Case rates before those rates are compared with the rates in the 7(b)(2) Case.

"Within or adjacent" direct-service industrial customer (DSI) loads are assumed to be served by the 7(b)(2) Customers for the entire rate test period.

The DSI loads assumed to be served by the 7(b)(2) Customers are assumed to be served wholly with firm power.

Appendix B to S. Rep. No. 272, 96th Cong., 1st Sess. (1979), is used to determine which DSI loads are "within or adjacent" to 7(b)(2) customer service areas, with modifications to reflect the actual status of BPA service to the DSIs.

To determine "Federal Base System (FBS) resources not obligated to other entities," DSI loads not "within or adjacent" are assumed to receive service from non-7(b)(2) Customers as the pre-Northwest Power Act BPA-DSI power sales contracts expire.

Section 7(b)(2)(D) identifies three types of additional resources that are assumed, in the 7(b)(2) Case, to meet the 7(b)(2) Customers' loads after the FBS resources are exhausted.

Specific additional resources are assumed to be used in the order of least cost first; generic resources then are used if necessary.

1.2.2 Implementation Methodology. A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on implementation methodology issues. The issues addressed in the hearing are discussed in the Administrator's Record of Decision (ROD) for Section 7(b)(2) Implementation Methodology (7(b)(2) ROD), published in August 1984. The Implementation Methodology and ROD are hereby incorporated by reference. The major issues resolved in the Implementation Methodology are discussed below.

Reserve benefits provided under the Northwest Power Act are quantified using the same value of reserves analysis used in the relevant rate case, modified to reflect that "within or adjacent" DSI loads are less than the total amount of DSI loads served by BPA. *See* Appendix B of Wholesale Power Rate Development Study, WP-02-FS-BPA-05. Within this rate proposal, reserve benefits provided under the Northwest Power Act are forecasted to be zero. BPA's Power Business Line (PBL) is assuming reserves will be purchased in market transactions or arranged on an individual contract basis. This change eliminates the need for a financing benefits analysis to quantify the value of reserves for this PBL power rate case. BPA's Transmission Business Line (TBL) may propose to purchase stability reserves from the DSIs in the TBL transmission rate case.

Financing benefits in the 7(b)(2) Case are quantified for planned or existing resources that have been acquired by BPA or are planned to be acquired in the Program Case during the 7(b)(2) rate test period. The financing benefits in the 7(b)(2) Case are estimated by a consultant, Sutro & Co. Incorporated, that estimates the sponsor's financial cost for the 7(b)(2) Case resources assuming that BPA did not acquire the resource output. The financing benefits in the Program Case for those resources required to meet the 7(b)(2) Customers' loads may increase the costs of those resources in the 7(b)(2) Case. When ownership of a resource is by non-preference customers, or is unidentifiable, the resource is assumed to be financed by a proxy financing entity comprised of all of the region's preference utilities, with shares in proportion to the utilities' firm power loads.

Natural consequences result from reflecting the five specific Section 7(b)(2) assumptions in the 7(b)(2) Case rates while keeping all the underlying ratemaking premises and processes the same for both cases. Three natural consequences were identified for possible modeling in the rate test: elasticity of demand, the level of surplus firm power available, and the size of nonfirm energy markets.

The 7(b)(2) rate test in this rate case is conducted using three large spreadsheet models, whereas in previous rate cases, a FORTRAN based mainframe computer model was used. The first of the spreadsheet models is the Program Case Rate Analysis Model (RAM-Prog), used to calculate Program Case rates. The RAM-Prog is the same model used in the rate case to calculate posted rates for the rate period. The second model is a 7(b)(2) Case version of the Rate Analysis Model (RAM-7B2). The RAM-7B2 model differs from the RAM-Prog by only the five assumptions specified in Section 7(b)(2) and the unavoidable natural consequences of those assumptions on the results of ratemaking processes. The third model is the Residential Exchange Model of the RAM (ResexRam), which calculates the costs of the Residential Exchange Program (REP) and electronically transfers that information to the RAM-Prog. The outputs of these spreadsheet models are in the Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A.

The projected rate for each year of the Section 7(b)(2) rate test period is discounted back to the first year of the rate proposal test period, using a factor based on BPA's projected borrowing rate for each of the rate test years. The discounted rates then are averaged for each case and the result rounded to the nearest tenth of a mill. The rate test triggers if the average of the discounted rates for the Program Case exceeds the average of the discounted rates for the 7(b)(2) Case by one tenth of a mill or more. If the rate test triggers, the difference between the two rates is multiplied by the general requirements of the preference customers in the test year to determine the amount of costs to be reallocated from the preference customers to other BPA loads in the test year.

2. METHODOLOGY

Implementing Section 7(b)(2) consists of incorporating the determinations from the Legal Interpretation and the Implementation Methodology ROD into the RAM-Prog and RAM-7B2 models.

2.1 Sequence of Steps

The RAM-Prog and RAM-7B2 models simulate BPA's ratemaking process by performing the steps needed to develop wholesale power rates. Each step is described as it is performed to calculate rates for the Program Case and the 7(b)(2) Case.

2.1.1 Program Case RAM. The RAM-Prog model calculates annual Program Case rates for the 2002 rate case rate period (Fiscal Years (FY) 2002-2006) and the following four years (FY 2007-2010). The method of calculating rates and the data used to calculate rates for the Program Case of the 7(b)(2) test are identical to those used in calculating average rates for the five-year rate period.

2.1.1.1 Sales. The sales forecast used to develop rates for the Program Case covers the period FY 2002 through FY 2010, and is the same forecast used to develop BPA's proposed rates.

Sales forecasts were developed for the region's publicly owned utilities using an adjusted Northwest Power Planning Council (NWPPC) forecast. Exchange loads were obtained either from information provided by the utilities themselves, 1996 data escalated to the FY 2002-2010 test period, or data collected from other public sources. For purposes of the 7(b)(2) rate test, BPA is forecasting it will sell 990 average megawatts (aMW) to the DSIs. Sales to Federal agencies and capacity/energy exchanges are contractually determined and are input to the RAM-Prog.

BPA's total sales obligations are comprised of public utility, investor-owned utilities (IOU), DSI, Federal agency, Residential Exchange, and FPS contractual sales. All forecasted sales are entered into the RAM models with diurnally and seasonally differentiated energy and seasonally differentiated demand billing determinants. Documentation for these forecasts of regional power loads appears in the Loads and Resources Study, WP-02-FS-BPA-01, and Loads and Resources Study Documentation, WP-02-FS-BPA-01A.

2.1.1.2 Load/Resource Balance. The RAM-Prog model does not perform load/resource balance calculations. Rather, the model depends on the load/resource balance performed in the Loads and Resources Study, WP-02-FS-BPA-01. Data from the Loads and Resources Study, WP-02-FS-BPA-01, are used in the Energy Allocation Factor model (EAF01_05) to ensure that resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves Priority Firm Power (PF) loads (contract, Federal agency, public utility, and Residential Exchange loads) until FBS resources are exhausted. Residential Exchange resources then are used to serve any remaining PF load. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining Residential Exchange and new resources are used to serve this combined rate pool.

2.1.1.3 Revenue Requirement. FBS costs are based on the interest and amortization of the Federal debt for the hydro projects; planned net revenues; hydro operation and maintenance costs; costs related to WNP-1, -2, and -3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Hanford and Trojan nuclear plants; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. Residential Exchange resource costs are based on the average system costs (ASC) of utilities participating in the REP, including cost adjustments for deeming utilities. New resource costs are those of the Idaho Falls contract, the generation portion of competitive acquisitions, geothermal resources, the Cowlitz Falls Project, and firm purchased power. Other BPA costs include BPA's administrative and general costs, short-term purchase power costs, the costs associated with the WNP-3 Settlement Agreement, and the costs associated with BPA legacy conservation, conservation augmentation, and energy efficiency programs.

2.1.1.4 Cost Allocation. Allocation of projected costs to customer classes is performed on an average energy basis in the RAM-Prog and RAM-7B2 models. Generation costs are allocated by the use of Energy Allocation Factors calculated using the results of the Loads and Resources Study, WP-02-FS-BPA-01. Conservation and billing credit costs, BPA administrative and general expenses, energy service business revenues, and WNP-3 Settlement Agreement costs are allocated across all BPA firm loads. The cost allocation procedures for the Program Case are the same as those used to develop BPA's proposed rates.

2.1.1.5 Rate Design. The adjustments made to allocated costs in the RAM-Prog for the Program Case are the same as those made to develop BPA's proposed rates. These include adjustments for: (1) excess revenue credits; the surplus firm power revenue surplus/deficiency; (2) the Section 7(c)(2) delta and margin; and (3) the DSI floor rate adjustment; and the exchange cost adjustment. These rate design adjustments are discussed below.

Excess Revenues are earned from the sale of secondary energy that is made available by the assumption of the average of 50 water years for secondary energy generation capability. Excess revenues are credited to loads served by FBS and new resources. The RAM-Prog and RAM-7B2 models use the secondary energy sales revenue forecast produced by the Risk Analysis Model (RiskMod), documented in the Risk Analysis Study, WP-02-FS-BPA-03.

The Surplus Firm Power Revenue Surplus/Deficiency results when the available surplus firm power is sold at other than its fully allocated cost. In addition, BPA assumes that long-term extraregional contracts will continue in the power sales mode, at amounts and rates set by the individual contracts. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after transmission costs are taken out, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to firm loads served by FBS and new resources. The revenues from capacity sales are also treated like the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources.

The 7(c)(2) Adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. A net margin is used in determining the applicable DSI rate. The net margin subsumes the value of reserves credit and the typical margin adjustment. The net margin is 0.42 mills/kWh in nominal dollars.

The DSI Floor Rate test ensures that the DSI rate will not be lower than the Industrial Firm Power (IP) rate in effect for Operating Year (OY) 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the DSI rate is below that floor rate, the DSI rate is raised to the floor rate and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers.

The Residential Exchange Cost Adjustment alters BPA's revenue requirement because changes in the PF rate result in changes in the cost of the REP. The RAM-Prog iterates with the Residential Exchange Model (Resexram) to converge on the cost of the REP that is associated with the calculated PF rate. *See* section 1.2, Table COSA 06 of Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A.

Rate Mitigation, Low Density Discount (LDD) costs, and Conservation and Renewables Discount (C&R Discount) costs are included in the rate calculations for the PF rate class. For a further discussion of these items, *see* sections 2.8, 2.9, and 2.10 in the Wholesale Power Rate Development Study, WP-02-FS-BPA-05, respectively.

2.1.2 7(b)(2) Case RAM. The RAM-7B2 model calculates 7(b)(2) Case rates in the same way as the Program Case rates are calculated, except where Section 7(b)(2) of the Northwest Power Act requires specific assumptions to be made that modify the Program Case.

2.1.2.1 Sales. The sales forecasts input to the RAM-7B2 to calculate rates for the 7(b)(2) Case are the same sales forecasts used in the Program Case, with the following modifications. The 7(b)(2) Case utility sales are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation and billing credits. The 7(b)(2) Case also excludes Residential Exchange loads. Sales to "within or adjacent" DSIs, adjusted to exclude estimates of the Conservation/Modernization program, are assumed to be transferred to the service territories of the preference customers for the entire rate test period as 100 percent firm loads. Sales to DSIs not "within or adjacent" are assumed not to have occurred.

2.1.2.2 Resources. The size of the FBS is identical for the Program Case and the 7(b)(2) Case. If the FBS is insufficient to serve 7(b)(2) customer loads through the test period in the 7(b)(2)

Case, additional resources are assumed to come on-line. Consistent with the 7(b)(2) Implementation Methodology, three types of additional resources can be added to serve 7(b)(2) customer loads. The first type is actual and planned acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case. The second type is the existing resources of 7(b)(2) customers not dedicated to serving their regional loads. These first two types of resources include any BPA programmatic conservation. These first two types of resources are used in order of least cost first. The third type of additional resources, generic resources, is based on the costs of resources acquired by BPA from non-7(b)(2) Customers consistent with the Program Case. These resources are brought online if the first two types of resources are insufficient to meet the 7(b)(2) customer requirements.

The financing benefits analysis required by Section 7(b)(2)(E)(i) of the Northwest Power Act was performed by BPA's financial advisor, Sutro & Co. Incorporated. The financial advisor's analysis appears as Appendix A to this document. It shows that the estimated financing benefit of BPA's participation in resource acquisitions of BPA sponsored conservation and generation resources by public utilities is 14 basis points lower than the 7(b)(2) Case without BPA backing. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost of the 7(b)(2) Customers. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 24 basis points between an assumed revenue bond issued with and without a BPA contract for the Project. BPA-sponsored programmatic conservation is four basis points lower than the same activities under the 7(b)(2) Case without BPA backing. In the 7(b)(2) Case, resources acquired from non-7(b)(2) Customers, such as independent power producers, have a cost of financing 75 basis points lower than the Program Case, in which BPA would be using nontax-exempt financing.

The debt associated with the Idaho Falls Project was refunded to take advantage of lower interest rates. However, since the owner of the project, the City of Idaho Falls, can withdraw from the contract with BPA at its option, the new interest rate is not affected by Idaho Falls' contractual relationship with BPA. Therefore, no financing differential is associated with Idaho Falls.

2.1.2.3 Load/Resource Balance. The RAM-7B2 model adjusts the established load/resource balance from the Program Case in the RAM-Prog model to comport with the different loads and resource use restrictions found in the 7(b)(2) Case. The Program Case is in load/resource balance during the rate period. The size of the FBS and the amounts of balancing purchase power and augmentation power are the same in the 7(b)(2) Case as in the Program Case. In addition, the Program Case assumes a small amount of new resource power that is not assumed in the 7(b)(2) Case. Therefore, before going into the 7(b)(2) resource stack, the total resources available to serve firm load are slightly less in the 7(b)(2) Case than in the Program Case. The 7(b)(2) Case PF class loads are larger than the sum of the Program Case PF and IP class loads. In the 7(b)(2) Case, no conservation savings are assumed to have occurred and additional price-induced DSI load is assumed to be brought online. The slightly smaller resource amount and the larger load for service under posted rates in the 7(b)(2) Case result in less FBS being available to serve the Firm Power Products and Services (FPS) contracted-for-sales in the 7(b)(2) Case than in the Program Case.

Since, in the 7(b)(2) Case, the FBS is large enough to serve all 7(b)(2) customer loads and the resources from the 7(b)(2) resource stack can only be used to serve 7(b)(2) customer loads, no resources from the stack are used to serve such load in the final proposal. Therefore, in order to achieve a loads/resources balance in the 7(b)(2) Case, a portion of the FPS contracted-for-sales served in the Program Case is not served in the 7(b)(2) Case. The determination of which

Program Case FPS contracted-for-sales are served in the 7(b)(2) Case is shown in section 2.1, Table 7B2, Resource_01 of the 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A.

2.1.2.4 Revenue Requirement. The revenue requirement in the 7(b)(2) Case is comprised of the same types of costs and budget information as in the Program Case, with some modifications. The 7(b)(2) Case excludes Program Case revenue requirement amounts budgeted for conservation, direct generation acquisitions, and Residential Exchange costs. Repayment studies are then performed for each year of the 7(b)(2) rate test period using the same method as for the Program Case.

2.1.2.5 Cost Allocation. Section 7(b)(2) Customers are allocated costs of the FBS and new resource costs according to their use of the respective resources. Purchasers of surplus firm power are allocated FBS costs and new resource costs according to their use of the resources.

2.1.2.6 Rate Design. BPA's final rate proposal estimates reserve benefits provided by the DSIs to the PBL to be zero. *See* Appendix B of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05. However, an estimate of possible stability reserves provided by the DSIs to the TBL has been included. *See* section 2.3, Table RDS 11 of the Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A. Other rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case.

3. SUMMARY OF RESULTS

Results for the two cases are summarized in Tables 1 and 2 below.

3.1 Program Case. The Program Case rate for each year is based on the costs of the resources used to serve the 7(b)(2) Customers. The resource costs are then adjusted as described above and in BPA's final rate proposal. Table 1 below shows the projection of undiscounted nominal Program Case rates.

3.2 7(b)(2) Case. The annual amount to be paid by 7(b)(2) Customers for their power needs in the 7(b)(2) Case is based on the cost of FBS resources and the cost of additional new resources. These power costs include adjustments for reserves and financing, *i.e.*, the absence of the reserve benefits and financing benefits implicit in the cost of power in the Program Case. The power costs are then subject to the same cost and revenue adjustment allocations as the Program Case rates. Table 2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

3.3 The Rate Test. The RAM-Prog model performs the Section 7(b)(2) rate test after it and the RAM-7B2 model calculate the two sets of rates. First, the projected Program Case rates are reduced by the applicable 7(g) costs for each year. The applicable 7(g) costs are described in Section 7(b)(2) as "conservation, resource and conservation credits, experimental resources and uncontrollable events." The 7(g) costs quantified for BPA's final rate proposal rate test are comprised of BPA's acquired and projected conservation and billing credits, energy efficiency costs, and C&R Discount costs. The projected rates for each year then are discounted to FY 2002 using factors based on BPA's projected borrowing rate for each year. Table 3 below shows BPA's future borrowing rates that were used in the discounting procedure and the corresponding cumulative discount factors. The discounted rates for each case then are averaged over the test period, rounded to one decimal place, and compared (*see* Table 4 below). As shown in Table 4 below, the rate test triggers. Therefore, a rate adjustment is required.

TABLE 1
PROGRAM CASE RATES
(nominal mills/kWh)

Line No.	Fiscal Year	A Rate	B Applicable 7(g) Costs	C Net Rate *
1	2002	26.780	2.319	24.46
2	2003	27.386	2.302	25.08
3	2004	27.490	2.169	25.32
4	2005	27.545	2.162	25.38
5	2006	27.601	2.032	25.57
6	2007	29.067	1.850	27.22
7	2008	29.733	1.763	27.97
8	2009	31.167	1.734	29.43
9	2010	31.089	1.539	29.55

* Column A minus Column B.

TABLE 2
7(b)(2) CASE RATES
(nominal mills/kWh)

Line No.	Fiscal Year	A 7(b)(2) Rate
1	2002	20.17
2	2003	20.79
3	2004	20.88
4	2005	20.67
5	2006	20.93
6	2007	22.62
7	2008	23.17
8	2009	24.46
9	2010	24.58

TABLE 3
DISCOUNT FACTORS FOR THE RATE TEST

Line No.	Fiscal Year	A Annual BPA Borrowing Rate [1]	B Cumulative Discount Factor [2]
1	2002	.0708	.9339
2	2003	.0689	.8737
3	2004	.0690	.8173
4	2005	.0688	.7647
5	2006	.0685	.7157
6	2007	.0681	.6700
7	2008	.0677	.6275
8	2009	.0672	.5880
9	2010	.0667	.5513

---

[1] 2002 Revenue Requirement Study Documentation, WP-02-FS-BPA-02A, Chapter 6.
[2] Column B_t = Column $B_{t-1}/(1 + \text{Column } A_t)$; Fiscal Year 2002 equals 1.

TABLE 4
COMPARISON OF RATES FOR TEST
(2002 mills/kWh)

Line No.	Fiscal Year	A Discounted Program Case Rate	B Discounted 7(b)(2) Case Rate
1	2002	22.844	18.834
2	2003	21.915	18.167
3	2004	20.695	17.062
4	2005	19.410	15.804
5	2006	18.299	14.977
6	2007	18.236	15.159
7	2008	17.552	14.538
8	2009	17.307	14.384
9	2010	16.289	13.551
10	Average Rate	19.2	15.8
11	Difference of Average Rates		3.4

APPENDIX A

SECTION 7(b)(2) RATE TEST STUDY

FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR

SECTION 7(B)(2) RATE TEST

SUTRO & CO. INCORPORATED

APPENDIX A TO:

7(B)(2) RATE TEST STUDY, WP-02-FS-BPA-06

SECTION 1

PURPOSE OF REPORT

The purpose of this report is to provide a summary of our conclusions and major assumptions concerning the "reduced public body and cooperative financing costs" as described in Section 7(b)(2)(E)(i) of the Northwest Power Act.

In providing the enclosed summary of our conclusions and major assumptions, we have relied upon our professional experience and expertise in matters concerning the overall credit markets, the activities of BPA and other public and private utilities in the Pacific Northwest (PNW).

Information utilized in reaching the conclusions contained herein rely, in part, on assumptions concerning historic valuation of reserve benefits; expected future resource acquisition costs, and the timing thereof, for BPA from FY 2001-2002 through 2010-2011; and the ownership shares in the hypothetical financing entity established for the purposes of applying the 7(b)(2) methodology. In all other matters, we have made only those assumptions that are consistent, in our opinion, with generally accepted conclusions concerning the credit markets and the conditions under which resource acquisition programs similar to that envisioned by BPA would likely occur.

SECTION 2

INTRODUCTION

The Northwest Power Act requires that the Administrator of the BPA periodically review and revise the rates for the sale of Federal power and for the transmission of non-Federal power. As part of the process of reviewing and revising the rates for firm power to be charged its preference, DSIs, IOUs, and other customers, the Administrator must follow the requirements of Section 7(b)(2) of the Northwest Power Act. Section 7(b)(2)(E) requires that the Administrator assume that:

> "the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal Base System resources, identified under subparagraph (D) of this paragraph and reserve benefits as a result of the Administrator's actions under this chapter were not achieved."

Section 7(b)(2)(D) specifies the assumptions to be made to meet public body, cooperative, and Federal agency customer (7(b)(2) Customers) loads. After meeting contractual obligations with FBS resources, additional resources can be added to meet loads of the 7(b)(2) Customers. These additional resources can include: actual and planned resources acquired from 7(b)(2) Customers; existing 7(b)(2) Customer resources not dedicated to their own loads; and generic resources acquired from non-7(b)(2) Customers. These resources are assumed to include any conservation programs undertaken or acquired by BPA.

The financing benefits of constructing the reserves relates to the load of the DSI customers. The current DSI contracts provide the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of the DSI loads. In the 7(b)(2) Case, the DSI loads are served by utilities in the Northwest instead of BPA. The 7(b)(2) rate test also requires the assumption that these utilities would have to provide their own reserve resources, and that the utilities would finance reserve resources without BPA participation. In other words, BPA's analysis of the value of the restriction rights in its rate cases contains the assumption that the financing costs associated with such reserves would be different were reserves acquired by regional utilities.

Unlike BPA's past rate case, BPA's PBL is forecasting a zero purchase of supplemental reserves from the DSIs in the current rate case. Therefore, the 7(b)(2) study will not include resource acquisitions by the Joint Operating Agency (JOA) for the replacement of supplemental reserves provided by the DSIs.

This report provides our conclusions concerning financing costs for BPA's public body, cooperative and Federal agency customers arising from an application of the 7(b)(2) assumptions contained in the Northwest Power Act. The conclusions presented in this report represent our opinions as investment bankers familiar with the domestic credit markets and with bond issues for both public power agencies and IOUs in the PNW. Given the assumptions noted in this report, our conclusions represent the most probable situation, had the hypothetical situation described in the Northwest Power Act occurred.

SECTION 3

EXECUTIVE SUMMARY

This report derives estimates of the interest rate differentials associated with the different classes of resources identified in Section 7(b)(2) of the Northwest Power Act with and without a BPA contract. The results are summarized as follows:

Resource	Program Case Interest Rate with BPA Backing	7(b)(2) Case Interest Rate without BPA Backing	Interest Rate Differential (basis points)
Named			
Idaho Falls	N/A	9.00%	N/A
Cowlitz Falls (1)	5.61%	5.85%	24 basis points
Conservation			
BPA Sponsored	6.82% (5)	7.62%	(80 basis points)
Other Public (2)	7.48%	7.62%	14 basis points
Generation			
Public (3)	7.48%	7.62%	14 basis points
Non-7(b)(2)(4)	8.37%	7.62%	(75 basis points)

N/A = Not Applicable.
(1) Reflects refunding issue sold August 24, 1993.
(2) Includes Billing Credits (Conservation and Generation) and Competitive Resource Acquisitions (Conservation).
(3) Includes Competitive Resource Acquisitions (Generation).
(4) Includes resources acquired from non-7(b)(2) Customers such as independent power producers.
(5) Fiscal 1982-99 average BPA historic long-term interest rate.
(6) From page A-29.

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown above are derived from historic borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The interest rate differentials are indicative of the interest rate differentials for projected borrowing costs for the period encompassing BPA's current rate case.

SECTION 4

ASSUMPTIONS

In making our assumptions, we have used the types of financing that most likely would be or could have been used at the time of funding the hypothetical resources acquired according to the terms of the 7(b)(2) rate test. We have relied upon only those most common and accepted legal and financing structures for the hypothetical public financing entity that the 7(b)(2) Customers are assumed to have formed. Similarly, discrete borrowings undertaken by 7(b)(2) Customers and non-7(b)(2) Customers, would be assumed to be financed using customary public financing methods for long-term fixed rate financing. Such assumptions as to legal and financing structure represent, in our opinion, the most prevalent means for financing large-scale resource acquisition programs similar to what BPA or its customers could have undertaken or would utilize in the future.

As noted above, the Northwest Power Act requires that an estimate be provided of the financing costs to customers in the 7(b)(2) Case because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after BPA's FBS resources are exhausted. Initially, to replace reserve benefits provided by the DSI load, the benefits are estimated assuming that the 7(b)(2) Customers acquired peaking facilities in FY 1981-1982. An assumption has been made, with which we concur, that the 7(b)(2) Customers would have formed a JOA where the financing would have been the responsibility of the participant agencies in the financing. This would have been a similar but not identical legal structure to Energy Northwest such that underlying legal obligations would have been clearly enforceable.

The member agencies of the JOA are listed in Appendix A along with their respective shares. Appendix B lists relevant ratings assigned by Moody's Investors Service, Inc. (Moody's) and Standard & Poor's Corporation (S&P) as of March 8, 1999. These ratings are approximately those which were accorded the same entities in 1982 with some upward revisions. We would note that the top eight member agencies comprise approximately 56.31 percent of the participating shares and are all currently accorded ratings of “A” or higher from Moody’s and S&P. Seven (7) of these actually carry current ratings of “A1” or “A+” or higher from at least Moody’s or S&P. Eight (8) of the 10 non-generators are participants of up to 1 percent and are currently rated at least “A” by either Moody’s or S&P.

All of the member agencies are assumed to have signed “take-or-pay agreements,” such that each would pay for its proportionate share of the debt service on the financing regardless of whether or not the project produced the expected levels of output. In the event that one participant failed to pay its share of the debt service, each remaining participant would be responsible for an increased level of debt service of up to 125 percent of the member agency’s original commitment. Based on such a typical financing structure, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating of “A,” or slightly higher, from both Moody’s and S&P, the two largest and most respected rating agencies. In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA “take-or-pay” or “capability” power sales contract, we have assumed that the financing would have received and been able to maintain a rating of “Aa1/AA-,” from both Moody’s and S&P.

No external factors are assumed to impede the operations of the JOA. Such external factors include any referendum concerning the approval of a financing for which a favorable result is assumed. Any legal impediments that may have existed which would restrict the hypothetical financing agency’s access to the credit markets (such as the Washington State Supreme Court decision of June 1983 concerning Energy Northwest) are assumed to have been removed by corrective legislation or favorable judicial decision. Similarly, no external factors are assumed to restrict the financing of resources by 7(b)(2) Customers, non-7(b)(2) Customers or other entities in terms of assuming the various hypothetical borrowings made for the purposes of performing the 7(b)(2) test.

In estimating the financing costs for specific resources, such as the Cowlitz Falls Project, we have assumed a rating based upon the particular sponsor's credit rating, assuming no "dry hole" or construction and completion risk. Therefore, the ability of the Public Utility District No. 1 of Lewis County (Lewis County PUD), for example, to service its own load with the resource is also assumed in order to meet requirements for investment grade ratings from both Moody's and S&P. Similarly, we have estimated financing costs for other anticipated conservation and generation resource providers, assuming that suitable uses for the resource output were available.

SECTION 5

ASSUMPTIONS CONCERNING RESOURCE ACQUISITIONS

In previous rate cases, BPA has assumed the JOA will undertake two phases of resource acquisition. The first phase assumed the acquisition of resources to replace the reserve benefits provided by the DSI load that are not provided in the 7(b)(2) Case. Unlike its past rate case, BPA's PBL is forecasting a zero purchase of Supplemental Reserves from the DSIs in the 2002 rate case. Therefore, the 7(b)(2) study will not include resource acquisitions by the JOA for the replacement of supplemental reserves provided by the DSIs. The BPA TBL may purchase stability reserves from the DSIs. The cost of these reserves will be determined in the TBL rate case.

The resource acquisition program involves the resources listed in Appendix C. We would note that these resources consist of the acquisition of individual projects involving conservation resource and generation resource programs sponsored by 7(b)(2) Customers as well as a variety of other sponsors. As part of its resource acquisition programs, BPA has solicited resources through its Competitive Resource Acquisition Program, unsolicited proposals, BPA Billing Credits, and other programs.

The City of Idaho Falls entered into a Power Purchase Agreement dated April 1, 1982, with BPA for the purchase of all power and energy produced from three hydroelectric generating plants operated by the City of Idaho Falls (the Idaho Falls Project). Lewis County PUD entered into a Power Purchase Agreement dated May 23, 1991, with BPA for the output of the Cowlitz Falls Hydroelectric Project (the Cowlitz Falls Project).

BPA has solicited for resources through the BPA Billing Credits Policy contained in section 6(h) of the Northwest Power Act and the Competitive Resource Acquisition Program, which includes the Resource Contingency Program. Under the BPA Billing Credits Policy, BPA has contracted for the output of four projects consisting of South Fork Tolt, Wynocchee, Short Mountain Landfill, and Smith Creek which aggregate 20.0 aMW. Under the terms of the BPA Billing Credits Policy, BPA's obligation to purchase the output is subject to the availability of the resource and, therefore, we do not believe the existence of the BPA power purchase agreement to be material to the credit rating of the financing associated with these particular resources.

In general, the hypothetical financing agency consisting of the 7(b)(2) Customers would apportion the risks of resource acquisition due to non-completion, technical difficulties or other factors among the member agencies in proportion to their ownership shares. Similarly, individual resource sponsors are assumed to accept such risks without allocation to third parties. Thus, the risks of non-completion or technical difficulties are not assumed to be assessed for the purposes of this study as factors that would impact the financing costs of particular resources.

Financing of the balance of resource acquisitions is assumed to occur through a series of financings in anticipation of cash-flow requirements. All financings are assumed to be undertaken at fixed interest rates. The anticipated financings would generally involve level debt service. In the case of the JOA entity issuing revenue bonds, the financing would rank as parity debt with the revenue bonds assumed to have been issued in FY 1981-1982. The revenue bonds or project financings issued by, or entered into by, 7(b)(2) Customers, non-7(b)(2) Customers or other entities would have comparable features.

Financing of the Cowlitz Falls Project and the Idaho Falls Project is assumed to have occurred at the time when the sponsors of each of the projects issued revenue bonds to provide for the capital costs of each respective resource. Resources to be acquired from non-7(b)(2) Customers are assumed to be acquired on a project finance basis wherein BPA would contract to purchase power output in the Program Case or with the resource contracted with the JOA in the 7(b)(2) study.

In addition, where available, it is assumed that all financings are structured to take full advantage of tax-exempt financing, subject to the provisions of applicable tax law. Also, we would note that section 9(f) of the Northwest Power Act requires certain certifications by the Administrator prior to the acquisition of resources, which must be met in order that the exemption from gross income in section 103(a)(1) of the Internal Revenue Code of 1986 be achieved. As a result, the assumption is made for the purposes of the resource acquisitions contemplated with BPA, that the tax-exemption for financings, where available, will not be adversely affected and that BPA will be able to provide the certifications required under the Northwest Power Act.

We would also note that the assumed credit ratings on revenue bonds involving an obligation of BPA have remained stable in spite of recent events. Uncertain water conditions, the financial requirements of BPA's resource acquisition programs, fish and wildlife issues, and the decommissioning of the Trojan Nuclear Power Project are significant issues affecting the PNW and BPA's credit ratings. However, for the purposes of the 7(b)(2) rate test, no change in credit ratings is projected for BPA, or the 7(b)(2) Customers, as it pertains to the financing feasibility of particular resources financed with debt issued in the public credit markets.

SECTION 6

IDAHO FALLS PROJECT

On April 1, 1982, the City of Idaho Falls, Idaho executed a Power Purchase Agreement whereby BPA agreed to a long-term purchase of the output of three hydroelectric generating plants to be constructed in the service territory of the City of Idaho Falls. The City of Idaho Falls provided for the capital costs of constructing the three hydroelectric generating plants with the proceeds of revenue bonds issued in 1981 (the 1981 Bonds). The 1981 Bonds were advance refunded in 1985 and were the subject of an additional refunding and restructuring completed in 1991. The City of Idaho Falls has also recently completed an additional restructuring of its debt on a taxable interest rate basis.

Under the terms of the Power Purchase Agreement with the City of Idaho Falls, the City may deliver to BPA a notice of withdrawal of the total project generation effective no earlier than three years from the year in which such notice is given, but not before July 1, 1988, or after July 1, 1998. Because the revenues of the City's Electric System (as defined) secure the City of Idaho Falls revenue bonds issued to finance the Project, we do not believe the existence of the BPA Power Purchase Agreement to be material to the credit rating of these bonds. Therefore, the cost of the Idaho Falls Project resource would not change as a result of the financing assumptions required by the 7(b)(2) rate test.

SECTION 7

COWLITZ FALLS PROJECT

On May 23, 1991, the Public Utility District No. 1 of Lewis County, Washington, (Lewis County PUD) entered into an Amendatory Contract for Power Purchase (the Contract) whereby BPA agreed to enter into a long-term purchase of the output of a hydroelectric generating plant known as the Cowlitz Falls Project (Cowlitz Falls Project). BPA and Lewis County PUD agreed that Lewis would finance construction of the Project through the issuance of revenue bonds with BPA agreeing to pay to or on behalf of Lewis County PUD amounts equal to Project Power Costs (as defined) including Annual Debt Service (as defined) on such revenue bonds for the life of the Contract. On August 27, 1991, Lewis County PUD issued $171,095,000 in Public Utility District No. 1 of Lewis County, Washington, Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991 (the Bonds). The Bonds were rated Aa/AA with annual debt service payments of approximately $13,465,000 and a final maturity of October 1, 2024. More recently, the callable Bonds were advance refunded on August 23, 1993, which lowered their approximate annual debt service to $13,050,000.

Under the terms of the Contract, the primary source of security for the Bonds is revenues received from BPA pursuant to the Contract and a Payment Agreement (the Payment Agreement). Under the Contract, BPA is obligated to pay all project costs, including debt service, whether or not the project is completed or power is delivered. If BPA does not make payment under the Contract, it is obligated to pay debt service under the Payment Agreement directly to the bond trustee. Debt Service on the Bonds is an operating and maintenance (O&M) expense of BPA, having priority over payments of BPA’s Treasury debt and repayment of the Federal investment in the Columbia River Power System.

Because the revenues from the Contract and the Payment Agreement secure Lewis' revenue bonds issued to finance the Project, we believe that the Contract and Payment Agreement are the only means that qualify the Bonds for their current credit ratings. In fact, early attempts to provide financing for the Project on a basis where construction, performance and environmental risks were apportioned amongst the lenders and vendors for the Project were not successful. BPA, thus retains the "dry hole risk" for the Project and is obligated to pay debt service on the Bonds for their full term whether the Project is operating or not. For the purposes of the 7(b)(2) test, Lewis is assumed to accept the "dry hole risk" and that the Cowlitz Falls Project output would be dedicated to serving Lewis' own load.

The original bonds were priced on Tuesday, August 27, 1991, with a True Interest Cost of 7.10 percent. The refunding Bonds were priced on Tuesday, August 23, 1993, with a True Interest Cost of 5.61 percent. As of the close of business on that date, the 30-Year Treasury Bond was at an 6.19 percent yield and the Bond Buyer 25 Revenue Bond Index as of the close of business August 19, 1993, the date of compilation closest to the date of sale, was 5.61 percent. The 2022 maturity for the Bonds was priced at a 5.5 percent coupon at a dollar price of 99.871 percent with a yield of 5.65 percent which yield exceeded the yield on the Bond Buyer 25 Revenue Bond Index by four basis points. Revenue bonds issued on the same day by the Pilchuck Development Public Corporation in the State of Washington with a Baa1/BBB yield subject to alternative minimum tax carried a yield of 6 percent in 2023. No other comparable primary market revenue bond sales by A/A rated or JOA issuers occurred at the same point in time as the sale of the Bonds. Two issues were priced by South Carolina State Public Service (A1/A+/A+) and New York State Power Authority (Aa/AA-) at yields generally lower than the Lewis County PUD bonds. However, as these bond issues were sized at $631 million and $1,133 million, respectively, which creates additional demand from term bond buyers as well as the issuers' locations in specialty tax states with high personal income taxes, we do not view them as suitable comparable issuers.

In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers to consist of 24 basis points between an assumed revenue bond issued with and without a BPA contract for the Cowlitz Falls Project. This 24 basis point differential approximates the difference in borrowing yields between the Aa/AA rated Bonds and an A rated obligation based upon the Baa1/BBB rated revenue bond issue which sold at the same time as the Lewis County PUD Bonds, as adjusted for the decrease in yield for the alternative minimum tax effect on the same sale date for the Bonds.

SECTION 8

NON-7(b)(2) CUSTOMER RESOURCES

Private developers, industrial companies, utility subsidiaries, governmental and quasi-governmental entities all represent viable sponsors for developing power projects, though each presents specific regulatory, financing and operating issues which need to be addressed. A given project sponsor's level of experience and demonstrated success are strong indicators for the viability of an operator. Financing vehicles available to project sponsors will be either recourse, where the sponsor's balance sheet is relied upon for credit support, or non-recourse. In a non-recourse project financing, the strength of the project, not the strength of the sponsor, provides the support for the debt. Project financings would derive incremental benefits from inclusion of a BPA power purchase contract.

For the purposes of this analysis, it is assumed that BPA would enter into an all encompassing power purchase agreement whereby BPA would be obligated to pay on a basis where a pricing mechanism would cover a project's fixed and variable costs. As a result, the project's financing should be indifferent to the level of electricity actually purchased. Other factors including power delivery requirements, security deposits, performance criteria, regulatory out provisions, milestone criteria, force majeure events, security interests, events of default and remedies upon default are presumed to be resolved in a fashion which enables a project to be financed upon standard commercial terms.

Project sponsors which are private entities may or may not be able to qualify for tax-exempt financing for a particular project and generally may do so only where a facility qualifies as an "exempt facility" such as a waste to energy facility. Projects financed with tax-exempt financing would likely occur at interest rates comparable to those for the hypothetical JOA discussed in section 9. Projects financed with private sources of capital would likely be financed with high leverage, which is usually 75 or 80 percent but can be as much as 100 percent, which allows for a minimization of equity investment by the project sponsor. We assume that a project financing with a BPA contract would provide the means for securing debt financing at pricing which would be at the upper end of the quality range for similar projects. The perceived credit quality of the BPA contract obligation among potential financing sources would increase financing options for a given project.

Private financing costs for generating projects undertaken by private sponsors will vary from transaction to transaction based upon project economics and other factors. However, we believe that private financing for a project with a BPA contract could be arranged at 50 basis points over the lender's cost of funds which is assumed for the purpose of the 7(b)(2) rate test to be six month's London Interbank Offered Rate (LIBOR) with 100 percent financing of project costs. Without a BPA contract, and assuming the JOA issuing entity, borrowing rates would be equivalent to those for the hypothetical JOA discussed in section 9. Appendix D includes an 18-year history of monthly averages for six-month LIBOR along with the calculated borrowing rates for the same period. These rates have not been adjusted for the possible effects of entering into interest rate swaps or conversion agreements which could have the effect of fixing the interest rates on all or a portion of a financing for a period of time or the remaining term to maturity for the transaction.

However, in order to adjust the variable LIBOR interest rates to an estimated fixed interest rate for comparison purposes, we have assumed a 50 basis point addition to the LIBOR based interest rates to represent the amortized cost of an interest rate swap. The assumed interest rate differential between the taxable interest rate for the resource acquired from a non-7(b)(2) Customer and the hypothetical JOA is negative 75 basis points. This result is reached by examining average historic borrowing spreads over an 18-year period.

SECTION 9

JOA BORROWING COSTS

Accepted as noted below for information for FY 1994/1995 and thereafter, Appendix D is based upon an analysis of all competitive and negotiated bond issues for selected public power agencies over $50 million for the period from January 1, 1982 to March 8, 1999. One of the largest issuers throughout the early 1990s has been the Energy Northwest, which completed the advance refunding of high coupon net billed revenue bonds previously issued during the high interest rate environment of the early 1980s. Appendix D compares the true interest cost for each financing for each FY to the Bond Buyer 25-Bond Revenue Bond Index (Revenue Bond Index). The Revenue Bond Index currently consists of revenue bonds maturing in 30 years where 11 of the 25 bonds included in the index are electric power related financings. We would note that the Energy Northwest was added to the Revenue Bond Index effective September 27, 1990. In general, the Revenue Bond Index consists of issuers with an average rating equivalent to Moody's "A1" and Standard & Poor's "A+" with a concentration of issuers rated "A1/A+" or "AA/Aa" from at least one rating agency.

For the purposes of analyzing the anticipated correlation between ratings and borrowing costs, we have further segregated the power bond issues on a FY basis in Appendix D between those which carry ratings of at least "AAA," "AA" and "A" from either Moody's or S&P. Also, we have eliminated Energy Northwest from the list of power revenue bond issuers with at least "AA" from either rating agency in order to assess the effect that the sometimes heavy issuance of refunding revenue bonds by Energy Northwest may have had versus other less frequent issuers. The average true interest borrowing cost as a percentage of the Revenue Bond Index for each FY is summarized in Appendix E both with Energy Northwest included as well as with the Energy Northwest excluded.

Since the date of the previous June 1996 Section 7(b)(2) Rate Test Study, investors in municipal issues have evolved away from reliance on underlying issue ratings to predominately bond insured transactions. This phenomenon is consistent with a trend in the overall municipal securities markets toward "commoditization" of tax-exempt borrowings with investors favoring insured over uninsured transactions in order to avoid the need to monitor the credit strengths and weaknesses of individual issues. Since approximately 1994-1995, the incidence of "A" and "AA" rated, non-bond insured transactions of over $50 million in size has either declined or almost completely ceased, in the case of "A" rated transactions. However, the incidence of "AAA" rated transactions has increased markedly.

In order to provide a consistent analysis of relevant borrowing spreads between the "AA" and "A" rated transactions, Appendix E now relies upon Bloomberg Capital Markets fair value yield curves for spread information for fiscal years 1994/1995 and thereafter. The Bloomberg Capital Markets calculates an index for "AA" and "A" rated power revenue bonds daily as of close of business East Coast Time for a 25-year maturity. The fair market value yield curves rely upon a methodology involving option free yield curves calculated based upon contributors and bond issuance calendars. We have incorporated the appropriate values for the Bloomberg indices in Appendix E. The information appears to be generally consistent with information included from prior years based upon the actual issuance of power revenue bonds by different rated issuers.

Appendix D indicates that the issuance of revenue bonds by the "A" rated JOA power bond issuers occurred at the percentage spreads to the Revenue Bond Index as summarized in Appendix E. Appendix E shows that, in our opinion, borrowings by the JOA with an assumed rating of "A" could reasonably be expected to occur at interest rates approximating a similar spread to the Revenue Bond Index. The actual percentage spreads of the Revenue Bond Index for JOA power revenue bonds issued with "AA" or "AAA" ratings are also summarized in Appendix E.

The effect of the heavy issuance of refunding revenue bonds by the Energy Northwest is similar to the phenomenon that occurred during the early 1980s when Energy Northwest issued the revenue bonds which were most recently refunded during the late 1980s and early 1990s. During a period of heavy new issue supply by a single issuer, the interest rates on subsequent borrowings tend to increase both relative to the general market and to other comparably rated issuers with less active financing programs. However, in our opinion, the true borrowing costs of the JOA would more reasonably be expected to occur at or near the historic spread relationship to the Revenue Bond Index as long as multiple issues were separated by sufficient time in order not to create an oversupply of the same issuers' bonds in the credit markets.

The evaluation of the factors noted above leads to the conclusion that the costs of a future borrowing backed by a BPA resource acquisition contract could reasonably be expected to approximate the average of those achieved over the 18-year period shown in Appendix D. In other words, BPA could achieve an interest rate differential of approximately 14 basis points on future borrowings as compared to the hypothetical "A" rated JOA to acquire the resources shown in Appendix C. This basis point differential was arrived at by calculating the interest rate spread differences between the "AA" power revenue bond issuers (excluding Energy Northwest) and the "A" power revenue bond issuers over the most recent 18 FY period. We have summarized below the relevant Revenue Bond Index averages for FYs 1981-1982 to 1998-1999 year-to-date (March 8, 1999) along with the assumed and anticipated borrowing rates.

BOND BUYER REVENUE BOND INDEX, ASSUMED BORROWING RATES AND ANTICIPATED BORROWING RATES

Fiscal Year Averages

Fiscal Year	Bond Buyer Index
1981-82	13.250%
1982-83	10.130%
1983-84	10.434%
1984-85	9.900%
1985-86	8.257%
1986-87	7.678%
1987-88	8.402%
1988-89	7.165%
1989-90	7.506%
1990-91	7.197%
1991-92	6.690%
1992-93	6.058%
1993-94	6.078%
1994-95	6.574%
1995-96	6.005%
1996-97	5.872%
1997-98	5.406%
1998-Present	5.236%
Average 1981-82 to Present	7.658%

Assumed Borrowing Rates

Fiscal Year	BPA	JOA	Difference
1981-82	12.65%	13.31%	.66%
1982-83	9.86%	10.47%	.61%
1983-84	10.69%	10.74%	.05%
1984-85	10.35%	10.10%	(0.25%)
1985-86	8.49%	8.42%	(0.07%)
1986-87	7.77%	7.68%	(0.09%)
1987-88	8.50%	8.48%	(0.02%)
1988-89	7.01%	7.13%	0.12%
1989-90	7.62%	7.49%	(0.13%)
1990-91	6.96%	7.02%	.06%
1991-92	6.33%	6.35%	.02%
1992-93	5.73%	5.81%	.08%
1993-94	5.63%	5.98%	.35%
1994-95	6.34%	6.51%	.17%
1995-96	5.80%	5.96%	.16%
1996-97	5.61%	5.76%	.15%
1997-98	5.15%	5.31%	.16%
1998-99 (1)	4.99%	5.23%	.24%

	BPA		JOA		
Fiscal Year Average	**% of Index (2)**	**Rate (3)**	**% of Index (2)**	**Rate (3)**	**Basis Point Difference**
1981-82 to 1999 (1)	97.66%	7.48%	99.55%	7.62%	0.14

(1) As of March 8, 1999

(2) Based upon relevant spreads for "AA" and "A" power revenue bonds issuers versus Bond Buyer 25 Revenue Bond Index (the Index).

(3) Calculated by applying the percentage of the Index to the average of the Index for the period 1981-82 to 1999 (7.658%).

In our opinion, the above-assumed borrowing rates are reasonable estimates based upon the actual borrowing costs of municipal issuers during the indicated time periods. Many factors influence the movement of tax-exempt interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above. However, we believe the indicated basis point differential to represent a reasonable estimate upon which to base the portion of the 7(b)(2) test involving the hypothetical JOA.

We would note that the assumed borrowing rates as well as borrowing rate spreads shown above for FY 1981-1982 through 1983-1984 are greater than for subsequent years mainly due to the events surrounding the Energy Northwest default. An assessment of the combined effects on the borrowing costs of the hypothetical JOA due to the Energy Northwest default and the heavy volume of issuance of power revenue bonds during the early 1980s is necessarily subjective. The effects of the default and concerns about credit quality issues regarding all JOA's, as well as BPA, would have increased borrowing costs for the hypothetical JOA. More recently, while the effects of the default have lessened as evidenced by the ability of Energy Northwest and other JOA issuers to finance at historically attractive interest rate levels and spreads, new concerns have arisen about the competitiveness of electric utilities, including wholesale utilities such as BPA, to compete in a more competitive environment.

APPENDIX A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANT	% SHARE
Eugene Water and Electric Board	4.07
Seattle	16.42
Tacoma	10.06
PUD #1 of Chelan County	5.29
PUD #1 of Cowlitz County	7.57
PUD #1 of Douglas County	1.04
PUD #2 of Grant County	3.05
PUD #1 of Snohomish County	8.81
SUBTOTAL - GENERATORS (8)	56.31
Port Angeles	1.29
Springfield	1.30
PUD #1 of Benton County	2.46
Central Lincoln PUD	2.48
PUD #1 of Clark County	4.68
Clatskanie PUD	1.45
Franklin PUD	1.06
PUD #1 of Grays Harbor County	2.36
PUD #1 of Lewis County	1.17
Umatilla Electric Cooperative Association	1.14
SUBTOTAL - NONGENERATORS WITH A GREATER THAN 1% SHARE (10)	19.39
SUBTOTAL - REMAINING NONGENERATORS (99)	24.30
TOTAL (117)	100.00

APPENDIX B

RATINGS FOR
PARTICIPANTS IN HYPOTHETICAL PUBLIC FINANCING ENTITY(3)

PARTICIPANT	MOODY'S	S&P
Eugene Water and Electric Board	Aa1	AA
Seattle	Aa2	AA
Tacoma	A1	A+
PUD #1 of Chelan County(Hydro Consolidated System)	Aa3	AA
PUD #1 of Cowlitz County	A	A-
PUD #1 of Douglas County	A	A+
PUD #2 of Grant County	Aa3	AA-
PUD #1 of Snohomish County	A1	A
Port Angeles	--(1)	A
Springfield	A	A
PUD #1 of Benton County	A3	A-
Central Lincoln PUD	A	A+
PUD #1 of Clark County	A1	A+
Clatskanie PUD	--(2)	--(2)
Franklin PUD	--(1)	A-
PUD #1 of Grays Harbor County	A3	A
PUD #1 of Lewis County	A	A-
Umatilla Electric Cooperative Association	--(2)	--(2)

(1) No Non-bond insured electric revenue debt outstanding with underlying rating.
(2) No rated electric revenue debt outstanding.
(3) As of March 8, 1999.

APPENDIX C

HISTORIC AND ANTICIPATED FUTURE RESOURCE ACQUISITIONS (1980 $'s)

(000's Omitted)

CONSERVATION

Fiscal Year	New Investments	Expense	Total
1981-82	$ 52,415	$ 0	$ 52,485
1982-83	166,472	3,912	170,384
1983-84	52,430	11,139	63,569
1984-85	78,164	16,747	94,911
1985-86	72,002	2,482	77,484
1986-87	47,254	7,781	55,035
1987-88	36,327	12,122	48,449
1988-89	24,716	12,172	36,888
1989-90	21,533	15,102	36,635
1990-91	27,933	16,513	47,897
1991-92	44,396	26,098	70,494
1992-93	56,703	27,719	84,422
1993-94	64,155	24,964	89,119
1994-95	40,539	16,274	56,813
1995-96	20,867	23,045	43,912
1996-97	10,733	15,085	25,818
1997-98	7,323	17,409	24,732
1998-99	7,070	12,864	19,934
1999-00	492	13,647	14,139
2000-01	481	12,641	12,722
2001-02	0	8,534	8,534
2002-03	0	7,582	7,582
2003-04	0	7,516	7,516
2004-05	0	7,494	7,494
2005-06	0	7,434	7,434
2006-07	0	7,413	7,413
2007-08	0	6,629	6,629
2008-09	0	5,681	5,681
2009-10	0	5,537	5,537

APPENDIX C-CONTINUED

HISTORIC AND ANTICIPATED FUTURE RESOURCE ACQUISITIONS (1980 $'s)

(000's Omitted)

Other Acquisitions

Fiscal Year	Billing Credits Generation And Other	Competitive Acquisition Generation	Idaho Falls/ Cowlitz Falls	Geothermal	CARES Wind	Renewables	Total
2002	4,818	5,701	8,747	7,393	2,027	1,449	30,136
2003	4,781	5,632	8,546	7,197	1,990	1,310	29,456
2004	4,756	5,567	8,353	7,008	1,954	1,192	28,830
2005	4,741	5,503	8,171	6,825	1,925	1,104	28,270
2006	4,734	5,447	7,999	6,656	1,895	1,038	27,768
2007	4,743	5,459	7,837	6,494	1,868	978	27,379
2008	4,765	5,417	7,663	6,335	1,840	919	26,940
2009	4,793	5,376	7,493	6,178	1,812	1,520	27,171
2010	4,831	5,336	7,237	6,022	1,783	1,682	26,890

(1) All amounts shown are in 1979-80 dollars.
Source: Bonneville Power Administration.

APPENDIX D

HISTORIC AND ANTICIPATED FUTURE BORROWING COSTS
NON-7(b)(2) CUSTOMER RESOURCES

Assumed Historic Project Financing

		BPA		JOA	JOA Differential to	
Fiscal Year	6-Month LIBOR(1)	Average Variable Rate	Average Fixed Rate(2)		Average Variable Rate	Average Fixed Rate
1981-82	15.41%	15.91%	16.41%	13.31%	(2.60)%	(3.10)%
1982-83	10.29	10.79	11.29	10.47	(0.32)	(0.82)
1983-84	11.17	11.77	12.27	10.74	(1.03)	(1.53)
1984-85	9.57	10.07	10.57	10.10	.03	(0.47)
1985-86	7.65	8.15	8.65	8.42	.27	(0.23)
1986-87	6.55	7.05	7.55	7.68	.63	.13
1987-88	7.67	8.17	8.67	8.48	.31	(0.19)
1988-89	9.32	9.88	10.38	7.13	(2.76)	(3.26)
1989-90	8.27	8.77	9.27	7.49	(1.28)	(1.78)
1990-91	6.85	7.35	7.85	7.02	.33	.83
1991-92	4.20	4.72	5.22	6.35	1.65	1.15
1992-93	3.41	3.91	4.41	5.81	1.90	1.40
1993-94	4.29	4.79	5.29	5.98	1.19	0.69
1994-95	6.25	6.75	7.25	6.51	(.24)	0.69
1995-96	5.62	5.87	6.37	5.96	.09	(0.41)
1996-97	5.78	6.03	6.53	5.76	(.27)	(0.77)
1997-98(1)	5.74	6.24	6.74	5.31	(.93)	(1.43)
1998-99(3)	5.00	5.50	6.00	5.23	(.17)	(0.77)

HISTORIC AND ANTICIPATED FUTURE BORROWING COSTS
NON-7(b)(2) CUSTOMER RESOURCES

Assumed Project Financing

	BPA		JOA	JOA Differential to	
Fiscal Year Average	Average Variable Rate	Average Fixed Rate(2)		Average Variable Rate	Average Fixed Rate
1981-82 to 1998-99(3)	7.87%	8.37%	7.62%	(0.25)%	(0.75)%

(1) London Interbank Offering Rate.
(2) Includes amortized cost of interest rate swap assumed to be 50 basis points.
(3) *As of March 8, 1999.*

APPENDIX E

HISTORIC BORROWING SPREADS

FISCAL YEAR AVERAGES BBI REV DEX AS %

Fiscal Year	A	AA	AA(ex/SS)	AAA
1981-82	100.46%	102.16%	95.46%	109.84%
1982-83	103.32%	97.36%	97.36%	N/A
1983-84	102.89%	102.41%	102.41%	N/A
1984-85	102.02%	104.59%	104.59%	97.85%
1985-86	101.98%	102.82%	102.82%	86.23%
1986-87	100.04%	101.21%	101.21%	100.41%
1987-88	100.92%	101.12%	101.12%	97.95%
1988-89	99.45%	98.53%	97.81%	97.50%
1989-90	99.75%	101.49%	N/A	94.33%
1990-91	97.56%	100.54%	96.67%	97.40%
1991-92	94.97%	96.46%	94.63%	94.38%
1992-93	95.88%	94.64%	94.64%	97.01%
1993-94	98.37%	93.76%	92.68%	96.13%
1994-95	99.05%	96.42%	96.42%	96.06%
1995-96	99.23%	96.51%	96.51%	89.44%
1996-97	98.03%	95.47%	95.47%	96.94%
1997-98	98.23%	95.19%	95.19%	92.76%
1998-99(1)	99.79%	95.22%	95.22%	91.39%
Averages For:				
1981-82 to 1998-99(1)	99.55%	98.66%	97.66%	95.98%

---

(1) As of March 8, 1999.

Appendix E

HISTORIC BORROWING SPREADS-continued

	Anticipated Borrowing Rates				Change in Basis Points	
Fiscal Year	BBI	BPA AA(ex/SS)	AA	A	A to AA	A to AA (ex/SS)
1981-82	13.250	12.65	13.54	13.31	(0.23)	0.66
1982-83	10.130	9.86	9.86	10.47	0.60	0.60
1983-84	10.434	10.69	10.69	10.74	0.05	0.05
1984-85	9.900	10.35	10.35	10.10	(-0.25)	(0.25)
1985-86	8.257	8.49	8.49	8.42	(0.07)	(0.07)
1986-87	7.678	7.77	7.77	7.68	(0.09)	(0.09)
1987-88	8.402	8.50	8.50	8.48	(-0.02)	(0.02)
1988-89	7.165	7.01	7.06	7.13	0.07	0.12
1989-90	7.506	7.62	7.62	7.49	(0.13)	(0.13)
1990-91	7.197	6.96	7.24	7.02	(0.21)	0.06
1991-92	6.690	6.33	6.45	6.35	(0.10)	0.02
1992-93	6.058	5.73	5.73	5.81	0.08	0.08
1993-94	6.078	5.63	5.70	5.98	0.28	0.35
1994-95	6.574	6.34	6.34	6.51	0.17	0.17
1995-96	6.005	5.80	5.80	5.96	0.16	0.16
1996-97	5.872	5.61	5.61	5.76	0.15	0.15
1997-98	5.406	5.15	5.15	5.31	0.16	0.16
1998-99	5.236	4.99	4.99	5.23	0.24	0.24

(1) As of March 8, 1999.